# TECHNICAL REVIEW DOCUMENT FOR OPERATING PERMIT 95OPDE049

to be issued to:

Public Service Company of Colorado Denver Steam Plant Denver County Facility ID 0310041

Prepared on June 24, 1996 Revised October 30, 1996 Peter K. Nelson, Review Engineer

#### I. <u>Purpose</u>

This document will establish the basis for decisions made regarding the Applicable Requirements, Emission Factors, Monitoring Plan and Compliance Status of Emission Units covered within the Colorado Title V Operating Permit proposed for this site. It is designed for reference during review of the proposed permit by the EPA, during Public Comment, and for other interested parties. Information in this report is primarily from the application received on March 1, 1995 and additional information received on June 15, 1995. In addition, a site visit was conducted on August 21, 1995 to confirm the information in the application.

## II. Source Description

This facility generates steam sold for heating and other purposes and is classified under the Standard Industrial Classification 4961. The facility consists of two industrial boilers burning natural gas and/or fuel oil to produce the steam. Maximum steam production is given as 330,000 lbs/hr. A metal building provides shop and offices and houses both boilers and all mechanical equipment. A 500,000 gallon underground storage tank on the southwest side of the lot holds No. 6 fuel oil. A natural gas pressure regulating/metering station is located on the northwest corner of the lot. A metal building co-located with the gas metering station holds pressure and flow recorders as well as gas telemetry equipment.

The facility is located at 1875 Delganey Street just north of downtown Denver in Denver County, Colorado. There are no affected states within 50 miles of the plant. Two Federal Class I designated areas, the Eagles Nest Wilderness Area and Rocky Mountain National Park, are within 100 kilometers of the plant. The area in which the plant operates is designated as non-attainment for Carbon Monoxide, Ozone, and Particulate Matter under 10 microns ( $PM_{10}$ ). This source is considered to be a major source in a non-attainment area (Potential to Emit > 100 Tons Per Year) but was constructed prior to the adoption of New

Source Review (NSR) regulations in 2/1/72 and the implementation of Lowest Achievable Emission Rate (LAER) in 1/30/79. The facility has not undergone any major modifications which would trigger additional NSR review or LAER. Facility wide emissions are as follows:

Pollutant	Natural Gas Potential to Emit (TPY)	#6 Fuel Oil Potential to Emit (TPY)	1995 Actual Emissions (TPY)
NOx	1091	770	305
СО	79	70	22
VOC	3	4	1
$SO_2$	1	1642	8
PM	6	124	2
$PM_{10}$	6	112	2

Potential emissions are based upon 8760 hours/year of operation at maximum capacity. Additionally, potential SO2 emissions are based upon 0.74% sulfur by weight. Actual emissions are based upon the last Air Pollution Emission Notices (APENs) received by the Division. Updated natural gas values were reported for data year 1995 and were added to the last reported fuel use values for data year 1993. This facility is required to provide an updated APEN in the event that emissions of any of the above air pollutants increase 5% or 50 tons per year, whichever is less, above the level reported on the last APEN submitted to the APCD. Under the guidelines of EPA's Whitepaper for streamlining the operating permit process, actual emissions for the last data year were not required during the application process. Therefore, the Division assumes that emissions from this facility have remained the same or decreased since the last APEN submittal based upon the compliance certification in the operating permit application.

#### **III.** Emission Sources

The following emission units are specifically regulated under terms and conditions of the Operating Permit for this site:

<u>Unit S001</u> - Riley Stoker Model M-H, S/N: 3776, natural gas and No. 6 fuel oil fired steam boiler. Rated at 210 mmBtu/hr maximum heat input rate.

<u>Unit S002</u> - Combustion Engineering, Type 35-A-15, S/N: 85074, natural gas and No. 6 fuel oil fired steam boiler. Rated at 243 mmBtu/hr maximum heat input rate.

#### Discussion:

1. Applicable Requirements- Unit S001 was installed prior to 1972 and has undergone no modifications. No Construction Permit was required in 1972. As the unit is essentially "grandfathered" from existing Construction Permit requirements (Colorado Regulation No. 3, Part B, Section I.A.), there are few applicable requirements. For many pollutants, the unit has no limitations, however, for fee and inventory purposes actual emissions must be calculated.

Unit S002 was installed in February of 1974 and has undergone no modifications. The unit was issued Construction Permit C10, 361 which gave PSCo the authority to construct and install the equipment. However, no applicable requirements were attached to the permit. Essentially, the unit is considered to be "grandfathered" as well.

The units are subject to SO<sub>2</sub> emission standards for existing sources as stated in Colorado Regulation No. 1, Section VI.A.3.b.(I). The regulation requires that each unit not exceed 1.5 lbs SO<sub>2</sub>/mmBtu when burning fuel oil. Again, the facility is using EPA approved emission factors along with actual fuel usage. Based upon the current heat and sulfur content of the fuel oil in storage, the facility will be in compliance with the SO<sub>2</sub> emission standard. Currently, the sulfur content of the fuel burned is given as 0.74% by weight and would have to exceed 1.4% by weight (at the current heat content level) to exceed the standard. Because the standard is related to the heat and sulfur content and not fuel consumption, the facility will be required to demonstrate compliance with the standard on each occasion that both fuel oil is burned and the sulfur/heat content of the fuel has changed since the last firing. This reduces monitoring by measuring these values from the total volume of the underground storage tank and demonstrating compliance only when the overall composition of the fuel oil changes.

These units are subject to the particulate standard for fuel burning equipment as stated in Colorado Regulation No. 1, Section III.A.1.b. The regulation requires that units meet a lbs/mmBtu particulate matter (PM) emission limit (PE) based on the following equation:

 $PE=0.5(FI)^{-0.26}$  where FI=Fuel Input in Million Btu per Hour.

Because the facility is using EPA approved emission factors along with actual fuel usage, by calculation the standard will never be exceeded when burning natural gas. For example, when boiler S002 operates at its full capacity of 243 mmBtu/hr, the PE limit is 0.1198 lbs/mmBtu. By comparison, actual emissions from burning natural gas are calculated to be only 0.003 lbs/mmBtu. The same generally applies when burning fuel oil, however, depending upon the heat content of the fuel, the potential does exist to exceed the standard.

Also, fuel oils typically contain some weight percent of sulfur which directly impacts the amount of particulate emitted during combustion. Unlike the SO<sub>2</sub> standard, the PM standard is dependent upon the consumption of fuel/hr and the heat content of the fuel and actually varies inversely to the heat input in mmBtu/hr. Because of this inverse relationship, inputting the maximum design heat rate actually produces the lowest allowable limitation. Therefore, by calculating and demonstrating compliance with the PM standard at its lowest point (when fuel input is the greatest), the facility demonstrates compliance at all other levels. These values are essentially then fixed into the permit. Boiler S001, with a maximum design fuel input of 210 mmBtu/hr provides an allowable PM standard of 0.125 lbs/mmBtu, while Boiler S002, with a maximum design fuel input of 243 mmBtu/hr provides an allowable PM standard of 0.120 lbs/mmBtu. Like the SO2 standard, emissions in lbs/mmBtu are dependent upon the heat and sulfur content and not fuel consumption. The facility will be required to demonstrate compliance with the standard on each occasion that both fuel oil is burned and the sulfur/heat content of the fuel has changed since the last firing. Estimated actual emissions in lbs/mmBtu will be compared to the standard for compliance purposes.

The units are subject to restrictions on using oil as a backup fuel as stated under Colorado Regulation No. 1, Section VIII.A-E. These regulations restrict this facility from using fuel oil from November 1 to March 1 of each year except under certain circumstances. These circumstances are:

- 1. The supplier or transporter of natural gas imposes a curtailment or an interruption of service
- 2. For necessary testing of equipment used to operate the unit on oil, testing of fuel and training of personnel
- 3. When an equipment malfunction at the facility makes it impossible or unsafe for the unit to operate on natural gas.

Additionally, the units must meet a 20% Opacity Standard (Regulation No. 1, Section II) as described under the monitoring section below.

**2. Emission Factors-** Emissions from the boilers are produced from the combustion of organic fuels. The pollutants of concern are Nitrogen Oxide (NOx), SO<sub>2</sub>, Carbon Monoxide (CO), Volatile Organic Compounds (VOC), Particulate Matter, and a subset of PM, Particulate Matter under 10 microns (PM<sub>10</sub>). Small quantities of Hazardous Air Pollutants (HAPs) are also emitted due to incomplete combustion. The relative quantities of each pollutant are dependant upon the fuel burned. The main pollutants of concern with natural gas combustion are NOx and CO. Minor amounts of SO<sub>2</sub> are emitted due to mercaptan, a sulfur containing chemical added to pipeline natural gas so that it can be detected by smell. With fuel oils such as No. 6 NOx is again a concern, however, fuel oils typically contain some weight percent of sulfur which directly influences the emissions of PM and SO<sub>2</sub>.

Residual fuel oils such as No. 6 typically contain a higher percentage of sulfur than do distillate fuel oils like No. 2.

PSCo will be using general EPA approved emission factors. In general, AP-42 emission factors are accepted as representative for these boilers and are typically of good quality. EPA Document 450/4-90-003, AIRS Facility Subsystem- Source Classification Codes and Emission Factor Listing for Criteria Air Pollutants, essentially places AP-42 data into easily used tables. While the boilers are not identical, they fall within the same general classification and have similar emission rates. PSCo will be using No. 6 fuel oil emission factors for emissions and compliance purposes. However, the source may burn other fuel oils. These factors, for each fuel, are listed below:

FUEL: Natural Gas		FUEL: #6 Fuel Oil	
SCC: 1-02-006-01		SCC: 1-02-004-01	
Pollutant	Emission Factor (lb/mmScf)	Emission Factor (lb/1000 gallons)	
NOx	550.0	55.0	
СО	40.0	5.0	
VOC	1.4	0.28	
$SO_2$	0.6	158.6 (S)	
PM	3.0	12.0 (S)	
PM <sub>10</sub>	3.0	10.8 (S)	

Where (S) is the weight percent of sulfur in the fuel oil. The weight percent is multiplied by the emission factor to give an adjusted emission factor which then takes the sulfur content of the fuel into account.

The facility also has the capability to burn fuel oil and natural gas simultaneously. There are no readily available published figures for this scenario. However, based on engineering judgement, the emissions should be representative of each fuel fraction. As such, total emissions under this scenario will be estimated as the sum of emissions from the fuel oil fraction and natural gas fraction.

**3. Monitoring Plan-** Conditions 1.1 to 1.3 of the Operating Permit list the Monitoring and Recording provisions necessary to verify compliance with applicable requirements for these

boilers when burning natural gas. Conditions 2.1 to 2.8 and Conditions 3.1 to 3.8 do the same for fuel oil and fuel oil/natural gas, respectively. Natural gas fuel use will measured and recorded annually. Fuel oil use will be measured and recorded annually except as noted below.

Additionally, when burning fuel oil during the November to March period mentioned above, specific recordkeeping and monitoring requirements are spelled out by regulation. These requirements only apply when fuel oil is burned during the restricted period. At all other times, normal recordkeeping and reporting applies. The specific requirements are as follows:

- 1. Dates and number of hours fuel oil is burned.
- 2. Percent sulfur analysis of the fuel oil that is burned.
- 3. Number of gallons burned each day.
- 4. Reason(s) for the use of the fuel oil.

A fuel analysis from the total volume of the underground storage tank will be performed on each occasion that fuel is transferred to the underground storage tank from any other source, to determine the heat content and sulfur content of the fuel oil to be burned. These analyses will also be used when determining compliance with Regulation No. 1 emission standards for PM and SO<sub>2</sub>. Semi-annually a monitoring report will be submitted as shown in Appendix B of the operating permit. A compliance report as shown in Appendix C will be submitted annually and will detail any instances of non-compliance. Regulation No. 1, Section VIII, C, D, & E also requires that the records required during the fuel oil restriction be maintained for a period of two (2) years. However, this requirement is less stringent than the five (5) year recordkeeping period required under Part 70 of the Clean Air Act (amended). Therefore, the recordkeeping requirements under Regulation No. 1 are supplanted and satisfied by the reporting conditions in Section IV of the proposed permit (Regulation 1, Section VIII, D).

As stated above, both boilers have no criteria pollutant limitations except for PM and  ${\rm SO}_2$ . However, all sources are required to monitor and record emissions for fee and inventory purposes. To this end, the Division has included the emission factors for all pertinent criteria pollutants in the Operating Permit to be used by the facility to calculate their annual emissions.

The Division has determined, based upon AP-42 emission factors and engineering judgement, that visible emissions from boilers when solely burning natural gas will be insignificant. Therefore, solely burning natural gas is sufficient to ensure compliance with the 20% opacity standard. When burning fuel oil and/or a combination of fuel oil and natural gas, a visual observation of emissions will be performed using EPA Method 9 when the fuel oil is first burned and then daily thereafter when firing the fuel oil and/or a combination of fuel oil and natural gas.

**4. Compliance Status-** A historical review of the facility's master file did not reveal any past compliance or enforcement problems at this site. This facility certified that they were in compliance with all applicable requirements at the time of their Title V Operating Permit Submittal. Based upon the information provided and an inspection of the equipment covered in the application, this facility is considered to be in compliance with all applicable requirements.

## IV. <u>Insignificant Activities</u>

A list of insignificant activities was provided with the application. These activities do not pose a significant threat to air quality. These items were placed in an appendix in the proposed permit so that they would be of use during inspections. Of specific interest:

## Emissions from #6 Fuel Oil 500,000 Gallon Underground Storage Tank

The tank resides on the southwest side of the facility. The surface tension and viscous nature of #6 Fuel Oil results in extremely low VOC emissions through the surface vents. VOC emissions are below 1 TPY and are therefore insignificant under Colorado Regulation No. 3, Part C, Section II.E.3.fff.

#### V. Alternative Operating Scenarios

Three alternative operating scenarios are given in the permit. The facility may burn natural gas as specified under Section II, Conditions 1.1 through 1.3; No. 6 fuel oil as specified under Section II, Conditions 2.1 through 2.8; or a combination of natural gas and No. 6 fuel oil as specified under Section II, Conditions 3.1 through 3.8. The facility is required to maintain records, contemporaneous to the switch in operating scenarios, indicating which scenario is in effect.

## VI. Permit Shield

The facility did not request any specific permit shield items and none were included in the permit. However, during the analysis of the operating permit, it was determined that several requirements listed as applicable requirements were not, if fact, applicable. The requirements in question are:

1. Regulation No. 1, Section IV.B.1 requires a continuous opacity monitoring system for any fossil fuel-fired steam generator of a total rated capacity of or greater than 250 mmBtu per hour heat input.

2. Regulation No. 1, Section IV.B.2 requires a continuous emission monitoring system for SO<sub>2</sub> any fossil fuel-fired steam generator of a total rated capacity of or greater than 250 mmBtu per hour heat input.

These requirements were determined to be inapplicable since both boilers in operation at the facility are rated at less than 250 mmBtu/hr maximum heat input.

#### VII. Accidental Release - 112(r)

A provision under Part 70 of the Clean Air Act (amended) is the Accidental Release provisions of section 112(r). Under this program, EPA established a list of substances which pose the greatest risk of death or serious injury to humans or extreme harm to the environment. Additionally, a list of flammable substances and high explosives were set forth. Each substance was given a threshold or deminimis level by considering their individual toxicity, reactivity, volatility, flammability, explosiveness, and dispersiveness. Facilities using any of these substances in greater-than-threshold quantities are required to prepare and implement a Risk Management/Prevention Plan (RMPP) for those substances.

This facility has notified the Division (FAX from Donna Toeroek to Peter Nelson dated November 18, 1996) that they are not subject to the requirements of 112(r).